Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7279
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

May 8, 1997

Docket No. 50-366 HL-5396

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 2
Licensee Event Report
Loss of Main Condenser Vacuum Results in a Main
Turbine Trip and Automatic Reactor Shutdown

Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning the loss of main condenser vacuum which resulted in a main turbine trip and automatic reactor shutdown.

Sincerely,

Lewis Sumner

H. L. Sumner, Jr.

IFL/eb

Enclosure: LER 50-366/1997-007

cc: *Southern Nuclear Operating Company*
Mr. P. H. Wells, Nuclear Plant General Manager
NORMS

U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. K. Jabbour, Licensing Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. B. L. Holbrook, Senior Resident Inspector - Hatch

1/1

IE22

1089

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 5/31/95
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	1 OF 6

TITLE (4)
Loss of Main Condenser Vacuum Results in a Main Turbine Trip and Automatic Reactor Shutdown

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S)
0 4	2 2	9 7	9 7	0 0 7	0 0	0 5	0 8	9 7		0 5 0 0 0
									FACILITY NAME	0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR ? : (Check one or more of the following) (11)			
POWER LEVEL (10)	0 5 5	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (include area code)
Steven B. Tipps, Nuclear Safety and Compliance Manager, Hatch	AREA CODE 9 1 2 3 6 7 - 7 8 5 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On 4/22/97 at 1907 EDT, Unit 2 was in the Run mode at a power level of 1418 CMWT (55 percent rated thermal power). At that time, the reactor shut down automatically on Turbine Stop Valve and Turbine Control Valve fast closure when the turbine tripped on low condenser vacuum. Water level decreased due to void collapse from the rapid reduction in power and the trip of the operating Reactor Feedwater Pump (RFP) on low condenser vacuum. The decrease in water level resulted in receipt of Group 2 and Group 5 Primary Containment Isolation System isolation signals and closure of the Group 2 and Group 5 Primary Containment Isolation Valves per design. Water level reached a minimum of approximately 45 inches below instrument zero (113.44 inches above the top of the active fuel) resulting in automatic initiation of the Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) systems per design. Secondary containment automatically isolated and all four trains of the Unit 1 and Unit 2 Standby Gas Treatment systems automatically started on low low water level per design. Level was restored to normal within one minute by the RCIC and HPCI systems and the standby RFP. Pressure reached a maximum value of 980 psig; no Safety/Relief Valves lifted nor were any required to lift to reduce or control pressure.

This event was caused by reduced heat rejection from the main condenser resulting in a heat buildup in the condenser and a decrease in vacuum. The condenser waterboxes were vented, the circulating pump inlet screens were cleaned, and the redundant steam jet air ejector was placed into service.

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 4/22/97 at 1907 EDT, Unit 2 was in the Run mode at a power level of 1418 CMWT (55 percent rated thermal power). At that time, the reactor shut down automatically on Turbine Stop Valve (EIIS Code TA) and Turbine Control Valve (EIIS Code TA) fast closure when the main turbine (EIIS Code TA) tripped on a low condenser (EIIS Code SQ) vacuum of approximately -23 inches Hg. The low condenser vacuum trip occurred about six minutes after receipt of the low condenser vacuum alarm at -25 inches Hg.

Following the main turbine trip and automatic reactor shutdown, vessel water level decreased due to void collapse from the rapid reduction in power and the trip of the operating Reactor Feedwater Pump (RFP, EIIS Code SJ) also on low condenser vacuum. The decrease in water level resulted in receipt of Group 2 and Group 5 Primary Containment Isolation System (EIIS Code JM) isolation signals and closure of the Group 2 and Group 5 Primary Containment Isolation Valves (EIIS Code JM) per design. Water level reached a minimum of approximately 45 inches below instrument zero (113.44 inches above the top of the active fuel). The level decrease resulted in automatic initiation of the Reactor Core Isolation Cooling (RCIC, EIIS Code BN) and High Pressure Coolant Injection (HPCI, EIIS Code BJ) systems on low low reactor water level per design. Secondary containment also automatically isolated and all four trains of the Unit 1 and Unit 2 Standby Gas Treatment systems (EIIS Code BH) automatically started on low low reactor water level per design. Level was restored to normal within one minute of the automatic reactor shutdown by the RCIC and HPCI systems and the standby RFP. Operations personnel secured the RCIC and HPCI systems and subsequently maintained water level using the standby RFP.

Reactor vessel pressure reached a maximum value of 980 psig before decreasing to approximately 750 psig due to low decay heat load, cold feedwater injection, and continued operation of the main turbine steam seal system (EIIS Code TC). No Safety/Relief Valves lifted nor were any required to lift to reduce or control pressure.

CAUSE OF EVENT

This event was caused by reduced heat rejection from the main condenser resulting in a heat buildup in the condenser and a decrease in vacuum. The reduced heat rejection could have been caused by a decrease in effective circulating water system (EIIS Code KE) flow rate. It also may have been caused by a failure of the "B" (operating) steam jet air ejector (EIIS Code SH) to remove all of the noncondensable gases from the main condenser. The reduction in effective flow rate could have been caused by a circulating water pump pit (EIIS Code NN) water level decrease to near the minimum submergence and net positive suction head required for the pumps.

A review of main condenser waterbox (EIIS Code KE) inlet and outlet temperatures revealed the outlet temperature of the "A" waterbox began increasing approximately 90 minutes before the main turbine trip and automatic reactor shutdown. During this same period, the inlet temperature decreased by about two degrees Fahrenheit. Therefore, the waterbox differential temperature was increasing for 90 minutes prior to the event; this increase occurred during a time when reactor power (heat input to the main condenser) was steady or decreasing. An increase in differential temperature without a corresponding increase in reactor power could be indicative of decreased circulating water flow rate. It also could indicate a buildup of noncondensable gases around the shell side of the "B", "C", and/or "D" waterbox tube bundles resulting in more of the condenser heat load being carried by the "A" waterbox tube bundle.

Operations personnel venting the waterboxes at the time of the main turbine trip reported a mixture of air and water coming from the waterboxes. This indicates air may have been entrained by the circulating water pumps. Air entrainment could occur if the pump suction water level were near the minimum required submergence level. However, pump suction pit level is not continuously recorded; therefore, level near and at the time of the event is not available. Levels reported by Operations and Maintenance personnel several hours prior to and after the event were above the design minimum submergence for the circulating water pumps.

The operating steam jet air ejector may have failed to remove all of the noncondensable gases entering the main condenser. This could have resulted in the noncondensable gases collecting around the shell side of the tubes in one or more of the tube bundles, shielding the tubes from the exhaust steam from the low pressure turbine, and reducing the heat transfer capability of the condenser. However, the recorded flow rate of noncondensable gases from the main condenser was constant at approximately 35 standard cubic feet per minute (scfm) until about 45 minutes prior to the main turbine trip when the flow rate decreased to 32 scfm. Flow rate decreased again to 2.5 scfm about 15 minutes prior to the event. It appears there was not adequate time prior to the event

for noncondensable gases to collect around sufficient numbers of tubes to significantly decrease the heat transfer rate within the main condenser. It is possible, however, that some of the flow of noncondensable gases from the steam jet air ejector originated from leakage within the air ejector itself and a buildup of noncondensable gases did occur in the main condenser over a long period of time. Vacuum readings from multiple locations within the main condenser and outlet water temperatures from all four waterboxes are not recorded and therefore are not available to help perform a detailed assessment of conditions at various locations in the condenser.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv) because of the unplanned actuation of Engineered Safety Feature systems. The Reactor Protection System (EIIS Code JC), an Engineered Safety Feature system, actuated on Turbine Stop Valve and Turbine Control Valve fast closure when the main turbine tripped on low condenser vacuum. Following the automatic reactor shutdown, water level decreased due to void collapse and trip of the operating RFP. The decrease in water level resulted in the receipt of automatic Group 2 and Group 5 Primary Containment Isolation System isolation signals on low and low low reactor water level, respectively, and closure of the Group 2 and Group 5 Primary Containment Isolation Valves per design. The Primary Containment Isolation System also is an Engineered Safety Feature system.

The main condenser is a two-shell, single-pass, single-pressure, deaerating type with a hotwell and four water boxes. The condenser consists of two sections, and each section is located below one of two low-pressure elements of the main turbine. Low-pressure turbine steam is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows such as exhaust steam from RFP turbines.

Deaeration in the condenser removes normal in-leakage of air plus hydrogen and oxygen gases contained in the turbine steam due to dissociation of water in the reactor. The noncondensable gases are concentrated in the air cooling section of the condenser, from which they are removed by the mechanical vacuum pump at startup and by one of two, 100-percent capacity, three-stage, steam jet air ejector units during power operation.

The circulating water system is designed to remove the design heat load from the main condenser in closed cycle operation using mechanical draft cooling towers (EIIS Code KE). The system consists of the condenser, cooling towers, and circulating water pumps. It is designed to supply the condenser with cooling water at temperatures ranging from 37 degrees Fahrenheit to 90 degrees

Fahrenheit. The system is arranged with two, 50-percent capacity, motor-driven, vertical circulating water pumps located in a separate structure between the turbine building (EIIS Code NM) and the cooling towers. Fixed screens located at the pump structure prevent debris from entering circulating water pumps, piping, and the main condenser.

In this event, reduced heat rejection from the main condenser caused heat to buildup. This, in turn, led to a loss of vacuum, a main turbine trip on low condenser vacuum, and an automatic reactor shutdown on Turbine Stop Valve and Turbine Control Valve fast closure. Possible causes of the reduced heat rejection include a decrease in effective circulating water system flow rate or a failure of the operating steam jet air ejector to remove all of the noncondensable gases from the condenser.

Following the automatic reactor shutdown, water level decreased due to void collapse from the rapid reduction in power and the trip of the operating RFP on low condenser vacuum. The decrease in water level resulted in receipt of Group 2 and Group 5 Primary Containment Isolation System isolation signals and closure of the Group 2 and Group 5 Primary Containment Isolation Valves per design. Level reached a minimum of about 45 inches below instrument zero (113.44 inches above the top of the active fuel) resulting in automatic initiation of the RCIC and HPCI systems per design. Level was restored to normal within one minute by the RCIC and HPCI systems and the "B" RFP. Secondary containment automatically isolated and all four trains of the Unit 1 and Unit 2 Standby Gas Treatment systems automatically started on low water level per design. Pressure reached a maximum value of 980 psig; therefore, no Safety/Relief Valves lifted nor were any required to lift to reduce or control pressure.

All systems functioned as expected and per their design given the water level and pressure transients. Water level was maintained well above the top of the active fuel throughout the transient and was restored to normal within one minute of the automatic reactor shutdown. Therefore, it is concluded the event had no adverse impact on nuclear safety. This analysis is applicable to all power levels.

CORRECTIVE ACTIONS

The "A" (redundant) steam jet air ejector was placed into service upon unit startup following the main turbine trip and automatic reactor shutdown. Troubleshooting of the "B" steam jet air ejector will continue as necessary.

The main condenser waterboxes were vented and the circulating pump inlet screens were cleaned following the event.

Operations personnel have been instructed to maintain circulating water system pump suction pit level at or above 115 feet mean sea level. This is at least five feet above the design required submergence for the circulating water pumps. This level will continue to be assessed and may be changed if warranted.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

No failed components appear to have caused or resulted from this event.

A previous similar event in the last two years in which a loss of condenser vacuum led to a main turbine trip and reactor shutdown was reported in Licensee Event Report 50-366/1995-003, dated 9/28/95. In that event, air binding of the tube side of the main condenser "D" waterbox tube bundle resulted in a decrease in heat transfer, a buildup of heat, and a decrease in vacuum in the condenser. The air binding occurred as a result of air entrainment in the circulating water pumps when pump suction pit level decreased due to blockage of water from one of the cooling towers to the circulating water system flume. Corrective actions for the previous event included venting the "D" main condenser waterbox, removing the material blocking the cooling tower, and briefing Operations personnel on the proper method of venting waterboxes. These actions could not have prevented this event because it was not caused by blockage of water from a cooling tower or improper waterbox venting methods.